Service Date September 21,1984

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER of the Application by MONTANA POWER COMPANY for authority to establish increased rates for electric service in the State of Montana. Rate Design.	UTILITY DIVISION DOCKET NO. 83.9.67 ORDER NO. 5051f

APPEARANCES

FOR THE APPLICANT:

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FOR THE PROTESTANTS:

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FOR THE INTERVENORS:

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FOR THE COMMISSION:

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BEFORE:

THOMAS J. SCHNEIDER, Hearing Examiner
JOHN B. DRISCOLL, Commissioner
HOWARD L. ELLIS, Commissioner
CLYDE JARVIS, Commissioner
DANNY OBERG, Commissioner

Background

1. On August 3, 1984, the Commission issued Order No. 5051d. This order set forth the cost of service approach that MPC was to use to compute reconciled class revenue requirements. In the order, the Commission directed the Montana Power Company to file rate schedules which reflect an increase
in annual electric utility revenues of $4,106,915. Rates were to increase by a uniform percent for all but the irrigator class.

2. Pursuant to later Commission staff and Company communication, which revealed that the Final Order would result in a rebate, the Commission directed the Montana Power Company to defer any rate changes until the present order was issued.

3. On August 21, 1984 the Commission received the Montana Power Company's Motion for Reconsideration of Order Nos. 5051c and 5051d.

4. This order initially provides the Commission's response to the only Motion for Reconsideration of the Cost of Service Order No. 5051d, which was submitted by MPC.

5. Following Motions for Reconsideration, the Commission will review MPC's and Intervenors' rate design proposals for the various customer classes, followed by the Commission's

decisions. The discussion of customer class rate design will begin with a brief review of the rate design and rates that resulted from Phase II of Docket No. 80.4.2, which is the rate design presently in effect. Order No. 5051d Issues for Reconsideration

6. In its Motion for Reconsideration the Montana Power Company set forth nine separate issues for reconsideration. Certain of these issues involve actual requests, while others appear rhetorical.

7. Marginal Energy Costs Based On PROMOD Results. With this issue the MPC states that the Commission's comparison of the market value of energy to LaCapra's marginal energy costs is erroneous; apparently, the MPC desires a response from the Commission.

8. First. the Commission acknowledges the fact that the Black Hills rate combines energy and demand costs one price. However, the Commission's Finding that the market value of energy is clearly in excess of LaCapra's PROMOD output still stands. It is clear that the Pacific Power and Light/Black Hills Power and Light power sale is related to Colstrip 3. LaCapra, in turn has acknowledged that the primary purpose of Colstrip 3 is to provide energy and not demand (see Finding No. 34 of Order No. 5051d).

9. One could bicker about the share of the 3.7¢/kwh that is capacity related. It is unlikely, however, that if the Company chooses to engage in this exercise, that it will be able for example, to lower the 3.7¢/kwh rate down to LaCapra's marginal energy cost levels of 0.964¢/kwh - 1.125¢/kwh (see Finding No. 76 of Order No. 5051d). The Commission would also note that this 3.7¢ figure escalates

over time with full capital recovery beginning after the fifth year.

10. Power's Base-Peak Calculation. With this issue the Montana Power Company requests reconsideration of the Commission's finding that energy costs do not vary while demand costs do vary.

11. First, with regard to energy, cross-examination of Power (Tr. pp. 4991, 4992) explains why long-run marginal energy costs do not vary. [As discussed in Order No. 5051d short-run marginal energy costs do vary.] Furthermore, the Commission clearly stated in Order No. 5051d that the concept of short-run marginal energy costs is important; the problem is that the PROMOD output in this docket does not reflect current market conditions the marginal opportunity value of energy (see Finding No. 75 of Order No. 5051d) .

12. The reason for not abandoning the concept of short-run marginal energy costs is that in a state of a perfectly designed generation system, short-run and long-run costs are equal. The problem is that the Montana Power Company system is far from perfectly designed as evidenced by the fact that short- and long-run marginal energy costs are unequal.

13. The second part of this Motion deals with why demand costs vary. Assuming the Company is referring to seasons, then the reason is due to relative seasonal loss-of-load probabilities (LOLP). LOLP's were accepted for use in this docket for purposes of allocating annual demand (generation and transmission) costs to seasons by LaCapra, Power, Schoenbeck and Wilson.

14. Colstrip 1 & 2 Common Plant Transfers to Colstrip 3.

In this portion of its Motion, the Montana Power Company requests the Commission to reduce the installed cost of Colstrip 3 by the common plant transfers from Colstrip units 1 and 2. In the Cost of Service Order the Commission deducted the cost of the 230 kv transfers from the marginal cost of the 500 kv line.

15. The Commission denies this Motion. Although the Commission excluded the cost of the 230 kv transfers from the cost of the 500 kv line, it does not follow, from a consistency viewpoint, that the Colstrip 1 and 2 common costs should also be excluded. The Company's own data response indicates that certain common costs to Colstrip 1 and 2 should be transferred to Colstrip 3 (HRC No. 1-54).

16. Furthermore, the Company has provided no explanation for its current request except consistency. In fact, the Company's Exhibit No. 67 proposes to exclude the 230 kv transfers, while including the Colstrip 1 and 2 common costs. The time for MPC to logically argue for excluding the common costs was Exhibit No. 67: MPC did, and included these costs.

17. Marginal Cost of Capital Used in the Carrying Charge Calculations. There are two separate motions related to this issue. The first deals with the "appropriate marginal equity cost" included in the marginal cost of capital calculation. The second deals with the appropriate marginal cost of capital for the 500kv transmission line.

18. Regarding the first motion, the Montana Power Company alleges that the Commission has overstated the cost of equity used in the cost of service analysis. The Montana Power Company argues that the appropriate cost of equity for Colstrip 3 is that approved by the Commission in the instant docket.

19. The Commission finds that the Company is correct in this regard. The marginal cost of equity approved in Order No. 5051c of 14.25 percent should be used.

20. Regarding the second motion related to this issue, the Montana Power Company argues that, because the Commission indicated the 500kv transmission line and Colstrip 3 were unitary property, the same carrying charge be used with both.

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[1] If one takes the MPC's total cost estimate of $284,739,300.00 (from HRC-1 No. 54, page 1) and divides by 210,000 kw, one arrives at the same cost (actually, there is a $2.0 difference) as indicated on Exhibit No. 67 (Page 1, Line 1).

21. The Commission finds that the issue of unitary property and cost of capital are separable issues: just like variations in labor costs e. g., union, non-union, carpenter, electrician there are variations in capital costs: The Company would not, for example, suggest setting electricians' wages equal to carpenters' wages, although both factors of production were used to construct Colstrip 3. Unless the Company financed the 500kv transmission line with the lower cost of capital associated with Colstrip 3, the Company must use the higher carrying charge (13.74 percent, as adjusted for the allowed cost of equity of 14.25 percent) to annualize 500kv transmission line capital costs. The Commission notes that any variation in the weighted cost of capital between Colstrip 3 and the 500 kv transmission line should be due to the availability of pollution control bond financing for the generation related facilities.

22. Losses. The Company states that technical accuracy requires that marginal losses be used with energy and demand, and that losses must be recomputed excluding the 500kv transmission line if the line is excluded from rate base.

23. First, the Commission finds that technical accuracy would argue for using marginal, instead of average, losses associated with demand costs. Such data was not presented, however, in the docket; consequently, average losses for demand costs must be used. The Company should plan to address the issues of proper demand losses in its next electric docket that deals with class cost of service and rate design.

24. Regarding the recalculation of losses with the 500kv line excluded the Commission finds that the Company is correct. The marginal energy losses should be recomputed with

the 500 kv line excluded, and the cost of service study adjusted accordingly.

25. Determination of Seasons. In this issue the Montana Power Company states that, because the Commission adopted LaCapra's and Wilson's seasonal definitions, there exists clear evidence to support PROMOD results and their use in the ratemaking process.

26. The Commission finds that the issue of using PROMOD marginal running costs (e. g., 1985 costs) for price signals is separable from the issue of using statistical analysis of both running costs and loss of load for purposes of defining seasons. The former is at a specific point in time (e. g., 1985 costs) while the later is based on a long trend, I. e., 21 years.

26. From LaCapra's prefiled testimony (Exh. No. 2, p. RLC-13 and Exh. No. RLC-11), it is clear that the proposed seasonal split is based on PROMOD generated marginal running costs and loss of load probability. From Statement L (Appendix A, page 4) it is clear that the seasonal LOLP is almost constant on a 5, 10 and 21 year average basis. But during the same 21 year period the Montana Power Company clearly swings back and forth from being resource deficient to resource surplus. If that were not the case resources would not be added. It is this sort of stability that argues for using LaCapra's seasonal split.

28. Furthermore, the Montana Power Company's estimates of relative seasonal marginal running costs (winter/summer) become more distinct (the winter/summer cost difference increases) as we move from the present through the 21 year period (see Statement L, Appendix A, page 4) This fact

indicates the need for a seasonal split.

29. The fact that the Commission finds problems with the magnitude of marginal running costs at a point in time does not preclude the Commission from using evidence from long-run trends in loss of load and running costs to establish periods of different costs: it is the relative difference (running cost and LOLP) and not absolute difference that is at issue in defining seasons .

30. Montana Power Company Resource Additions. In this issue the Montana Power Company explains why LaCapra's and Gregg's resource plans differ.

31. The discussion ignores the fact that this sort of capricious swing in resource plan limits the usefulness of the LaCapra fuel offset cost of service approach.

32. Transmission as an Energy Cost for System Reliability and the 500kv Transmission. The Montana Power Company raised two reconsideration issues that are related:

> Finding 109 declares that one of the reasons transmission is added is for "system reliability", and references a LaCapra analysis. As the Order is currently written, there is double-counting involved. The Order simply pulls this cost from a LaCapra exhibit which was otherwise rejected. LaCapra did, in fact, allocate transmission costs between demand and energy. Therefore, the PSC should modify its Order to show these "system reliability" costs as a deduction from total marginal transmission costs .

> Finding 106 finds that the total cost of the 500 kv line

should be included in the calculation of marginal energy costs. MPC has earlier argued in this Motion that the 500 kv line is necessary, in part, to ensure reliable service for the entire MPC system. The PSC should, therefore, eliminate the 500 kv line from the calculation of marginal energy cost. However, if the PSC continues to include it in the calculation of marginal energy cost, it should not be included in at 100% of its value. By its own argument in Finding 109, some part of it should be considered as transmission used for "system reliability. " (Motion, p. 40)

33. In the first issue the Montana Power Company states that the Commission simply pulled cost data from a LaCapra exhibit that was otherwise rejected It is correct that the cost data referred to in Order No. 5051d is from LaCapra's Exhibit No. RLC-7. However, if one looks a little further, one will find near coincidence between the demand related marginal cost of transmission on Exhibit RLC-7 and Exhibit RLC-8: $46.16/kw versus $46.19/kw. Perhaps a 3¢ transcription error was made or, perhaps LaCapra performed two different marginal cost estimates for demand related transmission (if this was done, it is not evident from LaCapra's testimony). The Commission assumes the former. Consequently, the Commission did not simply pull " . . . this cost from a LaCapra exhibit which was otherwise rejected. "

34. Regarding the second issue, the Montana Power Company in its Motion argues that the 500 kv line ensures reliable service for the entire MPC system, and requests that some part be considered for system reliability purposes, but 100 percent should not be considered energy related.

35. If the Commission were to assume 100 percent of the

500 kv line was for purposes of reliability where would the costs be accounted for? As an aside, it is interesting to note that the Company's position in its Motion is the opposite of that put forth in responses to data requests. In MPSC - 6-11- A and MPSC-16-25 two points are clear: (1) the 500 kv transmission line is "energy related" (emphasis added) and (2) the cost of the 500 kv transmission line is excluded from the marginal cost per kw of transmission demand (the $46.16 or $46.19/kw figures discussed above): On one hand the Montana Power Company says the 500 kv transmission line is energy related, on the other hand that it is not.

36. If one compares the Montana Power Company's energy related marginal cost of transmission on LaCapra's Exhibit No. RLC-7 (p. 1 of 2) of $4.62 to the Company's calculation on Exhibit No. 67 of $15.37/kw a stark contrast results. The latter represents only 50 percent of the 500 kv trans mission cost, and is further split between energy and demand (Exh. No. 67, page 2 of 5). Once more, on one hand (Data Response No. 6-llA) the Company says the 500 kv transmission grid is energy related, but on the other hand (Exh. No. 67) it has a demand function.

37. The Commission denies the Company's requests in this regard. The 500 kv transmission line (50 percent) should be reflected as energy related and included with the cost of Colstrip 3. The $4.62/kw energy related marginal transmission cost should also be used to proxy the reliability related energy costs of the transmission system. The Commission can only speculate how LaCapra arrived at a $4.62/kw estimate when just 50 percent of the 500 kv transmission grid alone amounts to $27.60/kw, as computed by the Company on Exhibit No. 67. LaCapra even suggests, in a data response (MPSC 6-llA), that the 500 kv transmission grid was only one of many

energy-related relocations (also see MPSC 16-25).

Rate Design

38. Residential. The current residential rate design features a minimum bill ($3.40/mo.) and seasonally differentiated energy rates; the winter energy rate (4.2579¢/kwh) is 20 percent greater than the summer rate (3.5483¢/kwh). The winter season runs from October 15 to April 14 for each customer class.

39. In this docket, based on its cost of service studies, the Montana Power Company (Richard LaCapra) proposed seasonally differentiated energy rates and a service charge ($4.50/month). The winter energy rate design features an inverted block structure with the break-point at 100 kwh; the summer energy rate design features a declining block rate structure with the same 100 kwh break-point (Exh. No. 2, Exh. RLC-18, pp. 1,2) . Generally, a principle rate design objective of LaCapra's was to set tail-block rates equal to marginal cost as derived from his Fuel Offset cost study. This objective is clearly seen with those rate schedules having separate energy and demand charges.

40. The Montana Consumer Counsel (John Wilson) computed rates for the residential class for two alternative cost allocation methods (the LOLP and single-CP methods); the resulting alternative energy rates, including demand costs, are both seasonally differentiated. The proposed customer charge (or service charge) ranged from $4.52 to $5.64 per month (see Exh. No 63, pp. 91, 92). The MCC also developed time-of-day (TOD) rates for this class (Exh. No. 63, p. 94).

41. The Human Resource Council (Thomas Power) proposed

significant changes to the present residential rate design. First, Power proposed a minimum bill (prior to implementation of Docket No. 80.4.2 rate design changes a service charge was tariffed), as is currently tariffed, but equal to $3.0 per month.

42. Power also proposed an inverted block rate structure (Exh. No. 39, pp. 99-147). Power's lifeline-like rate would feature a 25 percent differential between the initial and tail-block rates: the initial block rate would equal 75 percent of the tail-block rate. Under his proposal the winter and summer initial-block break-point would be 400 kwh/month and 300 kwh/month respectively. Power proposed that all customer classes " . . . pick up the revenue responsibility previously carried by the small residential customers" (Id., p. 143)

43. Power favors seasonal rates as long as ". . . they are carefully constructed to minimize the impact on small and low income users. . . " (Id ., p . 145) .

44. The Commission finds merit in tariffing a service charge combined with seasonally differentiated energy rates (It should be noted, however, that because residential customers are not demand metered, the energy rate actually combines energy and demand charges). The winter season for this and subsequent rate schedules should begin with the December billing cycle (roughly December 20 each year) and end with the March billing cycle (roughly March 20 each year); all tariff sheets should reflect this generic seasonal definition.

45. While there may be merit to an inverted block rate structure, the Commission finds relatively more merit in

moderating the rate design changes to this customer class. Furthermore, to properly reflect the seasonal differential in demand costs it would seem that the inverted block rate structure would have to be combined with seasonally differentiated rates, yet no testimony on the resolution of this problem was preferred.

46. An additional reason for not tariffing an inverted block rate structure, in this instance, is one raised indirectly by Power. Power argued against seasonally differentiated rates because " . . . a baseload facility is built to serve customers at all times of the year, and for that reason, long-run incremental costs associated with that base-load facility should be reflected at any time that facility's being used" (Tr. pp. 4855-4856). The Commission finds the same argument equally applicable to kwh energy consumption regardless of the block (initial or tail) of consumption.

47. The service charge shall equal $2.0 per month. This rate is less than the marginal customer cost of $3.14/month and, in the Commission's estimation, is preferred to a minimum bill for two reasons. First, there are certain costs (e. g., meters, meter reading, billing, etc.) that are incurred regardless of the level of energy consumption. Second, the Commission is unable to accurately verify revenues generated by a minimum bill.

48. Based on the relative demand costs between seasons, the Commission finds merit in increasing the existing winter/summer differential from 20 percent to 30 percent. In fact, a larger differential is justified based on generation- and transmission-related demand costs combined with the seasonal loss-of-load probabilities which were presented in

this docket.

49. The following table summarizes the approximate resulting residential rates:

Table 1

Residential Rate Design[1]

Service Charge	$2.00/month
Energy:	
Winter	4.01¢/kwh
Summer	3.09¢/kwh

[1] The above rates are estimated and assume a $62,544,885 revenue requirement; this figure will have to be revised to reflect the $62,632,810 revenue requirement in the Company's August 20, 1984 workpapers. Also, the Company must account for the employee discount for its customers.

50. Regarding service to residential two or more apartments, the Commission finds that such customers, if demand metered, rightfully belong on the General Service rate schedule since the residential tariff does not have a separate demand charge. If not, they belong on the residential rate schedule.

51. Regarding the revenues unrecovered from MPC employees due to the Company's employee discount, the Commission finds that all class' rates should be increased by a uniform percent.

52. General Electric. The current rate design features seasonally differentiated energy and demand charges, and a minimum bill ($6.45/month). The winter and summer energy rates for the first 5000 kwh per month are 3.338¢/kwh and 2.7816¢/kwh respectively; the rates for consumption in excess of 5000 kwh per month are 61.5 percent lower (the rate in

excess of 5000 kwh divided by the initial block rate). There is currently no demand charge for the first 10 kw/month; all additional kw are charged at $4.08/kw in the winter. The summer rate is 67 percent of the winter rate.

53. The current Phase II rate design reflects a major revision to the pre-Docket No. 80.4.2 rate design: rates prior to this docket featured a 7-step declining block structure.

54. In this docket the MPC proposed seasonally differentiated energy rates for the General Electric customer class. The MPC's proposed energy rates still reflect a declining block (5-step as opposed to the 7-step prior to Docket No. 80.4.2) rate structure (Exh. No. 2, Exh. RLC-118, pp. 3, 4). A demand charge for all kw in excess of 10kw per month was also proposed, but without any seasonal differentiation. Finally, the Company proposed a service charge of $6.65/month in lieu of the existing minimum bill.

55. The MCC developed illustrative rates for the General Electric customer class for the two alternative cost allocation methods discussed above. Energy rates (including demand costs) were differentiated by season and voltage level. The customer charge ranged from $6.63 to $8.27 per month (Exh. No. 63, p. 92). In addition, the MCC developed alternative time-of-day (TOD) rates for this class.

56. The HRC also proposed a rate design that differs from the MPC's. Specifically, Power objects to the declining block rate structure for this class as proposed by the MPC. As with the residential class, Power proposes an inverted block rate structure, noting that a flat tail block rate should be collected unless " . . . losses are significantly

different on the secondary, primary, and transmission systems, separate energy rates appropriate to these levels of delivery should be adopted" (Exh. No. 39, p. 154). Unlike with the residential class, however, Power proposes a strict intra-class recovery of the lower cost initial block energy rate for this class:

> Q. Does the witness propose that this lower cost energy block be recovered on an intra- or inter-class basis?
>
> A. Dr. Power would collect the costs of the lower cost energy block within the class. Those costs, however, should be established on a marginal cost basis (Data Response No. 39B to the Commission staff).

57. Power proposes a seasonally differentiated demand charge to reflect appropriate demand cost responsibilities. Power suggested that this rate schedule could be split into two separate schedules, one for demand metered and the other for nondemand metered customers (Data Response No. 39A to the Commission staff). No position on a minimum bill versus a service charge was stated.

58. There currently exists a tariff available for church owned sanctuary buildings used for public worship. The tariff includes an energy (3.6325¢/kwh) rate and minimum bill of $3.23/month. The MPC proposed to serve customers on this schedule on the General Electric tariff; that is, the separate All Electric Church tariff would be eliminated (Exh. No. 2, p. RLC-26).

59. The MPC also proposed a ne~v and separate tariff for the federal government's missile sites. The Company's argument for a separate schedule is " . . . the missile site rate is not at cost and thus cannot be placed on the general service schedule (Exh. No. 2, p. RLC-27). The proposed rate features a seasonally differentiated 3-step declining block

rate structure, a demand charge of $4.50/kw and an annual minimum bill of $86.72/kw of contract demand. As with the Electric Contract tariff (see Finding No. 58 below) the MPC proposed a tax adjustment clause (Exh. No. 2, Exh. RLC-18, pp. 9, 10).

60. The MCC proposed separate rates for the federal government's missile sites in accordance with the method used to develop the industrial class rates. Unlike the MPC, however, the MCC also proposed a separate rate schedule for Malmstrom Air Force Base (see Exh. No. 63, p. 93).

61. As with the residential rate schedule the Commission finds merit in moderating the rate design changes with the general service customer class. These changes are outlined below. The Commission also finds merit in billing the present electric church class, the missile sites, and Malmstrom Air Force Base on the general electric tariff. From data responses in this docket it is evident that these three groups of customers are not served at the transmission voltage level of service (see, for example, MPC data responses to the Commission staff: MPSC Nos. 13-1A, 13-5A, and 16-110 and W.P. Rule $14680, p. 2 of 50). To this end the missile sites should be billed individually and not conjunctively.

62. The Commission finds that a service charge of $3.0/month should be tariffed; this rate is less than the marginal cost of $4.99/month. The Commission's arguments for a residential service charge equally apply here.

63. The Commission finds that seasonally differentiated demand charges of $3.81/kw (winter) and $2.38/kw (summer) shall be tariffed. These rates reflect the current demand

charges ($4.08/winter and $2.72/summer) multiplied times their respective billing determinants with 10 percent of the resulting revenues shifted to the calculation of energy rates. The present 50 percent differential is also increased to 60 percent to reflect a gradual move toward the seasonal demand cost differential found in this docket.

64. The resulting rate design and energy rates are summarized in Table 2 below. The Commission finds that the existing seasonal energy differential of 20 percent shall be retained for rate moderation reasons. That is, although a single marginal energy cost results from the Power cost of service study, for reasons of rate moderation, the 20 percent differential shall be retained.

65. The Commission also finds that the number of kwh associated with 10kw of demand should be lowered from the present 5000kwh level to 3000kwh In a data response to the Commission staff (MPC-13-3D) the Company indicated that the kwh per 10kw of demand ranged from 1600 (winter) to 1400 (summer). In contrast, if one computes this class' annual load factor (using 442mw of peak demand and 2,213,341,900kwh), and in turn uses this percent to compute the kwh per 10kw of demand, one arrives at approximately 169kwh/month. Based on this evidence the 3000kwh/lOkw of demand appears reasonable.

Table 2

General Electric Rate Design[1]

[1]Estimated energy rates and actual demand rates and service charge. These rates assume a $70,096,026 revenue requirement which will need adjusting to reflect the reconciled revenues for

Service Charge/2 $3.00/month

	First 10kw	All Additional
Demand[2]	First 10kw	All Additional
Winter	No charge	$3.81/kw
Summer	No charge	$2.38/kw
Energy[3]	First 3000 kwh	All Additional
Winter	3.970¢/kwh	2.443¢/kwh
Summer	3.310¢/kwh	2.036¢/kwh

66. Due to an absence of certain billing determinant data the Commission was prevented from considering alternatives and a more refined rate design options for this class. The Company's next electric rate filing must provide a breakdown of kwh consumption per voltage level (secondary and primary) of service, in each season, for demand and nondemand metered general service customers. To this end, the existing seasonal definition should be used. It should be clear that the purpose of this data is to allow the Commission an opportunity to consider separating the current general service rate schedules into two separate schedules; as a result, the 3000kwh break point for energy and the "no charge" provision for the first 10kw of demand would very likely be eliminated.

67. In a related matter, the Commission questions the economic relevance of the 10kw of demand decision rule for demand metering general service customers. Two questions come to mind. First, is the 10kw break point correct today?

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the classes.

[2]These are the actual rates that should be tariffed.

[3]The calculation of these rates did not include billing kwh for the missile sites and MAFB; the Company, must include these billing determinants when computing energy rates. These rates reflect a simple uniform percent increase to the existing energy rates.

Second, is the 10kw break point (or, whatever break point is economically correct) also appropriate for other customer classes? The Company should address these issues in its next electric rate design docket.

68. The Company's proposed tax adjustment is denied for the reasons set forth in Finding No. 96 below.

69. Irrigation Pumping and Sprinkling. Out of Docket No. 80.4.2 Phase II a complex mix of irrigation tariffs resulted. The irrigation tariff options prior to Docket No. 80.4.2 included the General Electric (discussed above) tariff and an optional irrigation rate schedule: both featured at least a 6-step declining block rate structure. With the issuance of Order No.4714d (Docket No . 80.4.2 Phase II), the MPC was directed to grandfather the above tariffs and design a third tariff, the current tariff, that featured a flat energy rate, a monthly service charge, and a monthly minimum bill. This third tariff is mandatory for all new customers and optional for all existing customers.

70. In the present docket the MPC proposed the same summer energy rates for irrigation customers as proposed on the General Electric tariff. In addition, a Minimum Seasonal Bill of $22.15/hp billed was proposed (Exh. No 2, Exh. RLC-18, pp. 5, 6). As is evident from cross-examination of LaCapra the minimum seasonal bill is a residual calculation, but approximates costs

> Q. You will have to look at Page 31, but I'd like to start out with Page 2. And, looking at Page 32, is it true that the dollars per-horsepower estimate

you compute is Simply a residual calculation; that is, total irrigation revenue requirement less energy and demand revenues, divided by total horsepower?

A. Well, yes and no. The yes is that it is a residual, especially given the objective that demand and energy charges would be incorporated by the general-service tariff. (Tr. p. 4308, also see MPC Data Response No. 16-24 to the Commission staff).

71. The MCC proposed illustrative energy-only rates for the irrigation class that are seasonally and voltage level differentiated (Exh. No. 63, pp. 92, 93).

72. In hearing Ms. Shore asked the Irrigator's witness Yankel of his rate design preferences:

Q. As a hypothetical, if the existing rate design as referred to in your testimony were the rate design that flowed from the decision in 80.4.2, would your recommendation be the same; that is, to leave that rate design in effect rather than adopt any of the designs, especially the Montana Power Company's design, being proposed in this case?

A. Yes, as far as the rate design goes, yes. The right (sic) spread, obviously, that would be a different Matter, but given the new information we have now about the rate design, yes.

Q. Mr. Yankel, what I'm asking you to assume is that the rate design in 80.4.2 is in effect today. Is your testimony that there should be no change in the existing rate design?

A. Right. (Tr. pp. 5186-5190).

73. Because of the nature of the Power cost of service study adopted by the Commission, there resulted a substantial decrease in this class' annual revenue requirement. This result, in turn, requires the Commission to make a number of revisions to the tariff option that resulted from Phase II of Docket No. 80.4.2 (Order No. 4714d) .

74. First, however, the Commission finds merit in totally eliminating the existing two grandfathered rate options. That is, the rate design mandated by this order is the only irrigation rate design that shall be tariffed.

The Commission's primary reason for eliminating these two rate schedules is that declining block energy rate structures do not reflect the cost of energy resulting from the Power cost of service study. Secondly, the three existing irrigation rate designs impose unnecessary administrative costs on the MPC and, consequently, on all MPC ratepayers.

75. The Commission finds that the resulting irrigation rate design shall feature two rate elements, a service charge per month and an energy rate. The service charge shall equal $30.00 per season (normally May through October -- see MPC Exhibit No. 2, Exhibit No. RLC-18, p. 5 of 10). A seasonal service charge is preferred to a monthly service charge as some customers would only take service for perhaps a month, yet the meter investment, for example, would remain. The energy rate shall approximately equal 2.4961¢/kwh. Table 3 below explains these calculations:

Table 3

Irrigation Rate Design

Service Charge/1	$30.00/season
Energy/2	2.4961¢/kwh

76. This rate design is clearly not compensatory in terms of recovering unit marginal costs. The marginal cost of energy at the secondary voltage level is 3.81/kwh; the resulting rate is 2.496/kwh. Furthermore, demand costs are not recovered at all and amount to $17.55/kw ($2.19/kw/month) in the summer months for generation and transmission demand

costs plus 1.48/kw/month in the summer months for distribution demand costs.

77. In the future, this class' rate design will likely be altered to include a demand charge. At issue then is whether such a demand charge should be on a connected load (maximum horsepower rating) or actual metered demand basis. If the demand charge is on an actual metered demand basis, then the issue of what size loads should be demand metered is relevant (The above 10kw issue with general service customers discussed previously). It is clear from the Company's Rule No. S14680 workpapers (pp.33-35) that the Company is not consistently demand metering, for load data purposes or otherwise, customers with the same size irrigation pumps (e. g., there are 238 15hp pumps of which only 179 are demand metered). These issues shall be revisited and resolved in the Company's next electric rate case.

78. Electric Contract. The current rate design (resulting from Docket No. 80.4.2 Phase II) for Electric Contract customers features seasonally differentiated demand and energy charges and a contract based minimum bill. Energy rates have a 20 percent winter/summer seasonal differential; demand rates have a 50 percent differential.

79. The MPC's proposed revisions (Exh. No. 2, Exh RLC-18, pp. 7 and 8) to this tariff include a seasonally differentiated 2-step declining block energy rate (with the break point at 350 kwh per kw of metered demand), and a min imum bill equal to $7.66/kw of "maximum contract demand as specified in the Contract. " The basis for this minimum bill is LaCapra's fuel offset demand cost estimate.

80. A demand charge was proposed that reads as follows:

DEMAND CHARGE: First 5,000 kilowatts or less of metered demand @ $2,970.095.

All additional kilowatts of metered demand up to and including the Contract Demand @ $5.794019 per kw.

If served, all kilowatts in excess of Contract Demand, as specified in the Contract, will be billed at five (5) times the Demand Charge tail block of this schedule. (Exh. No. 2, Exh. No. RLC-18, p. 7 of 10.)

81. The last paragraph of this excerpt has been referred to as the "penalty" or "excess demand" provision. Haffey indicated that the "If served" provision sets MPC's maximum obligation to serve customers under normal circumstances (Tr. p. 3496). Haffey also indicated that the basis of the “(5) times the Demand Charge" provision is to " cover the cost responsibilities the Company might face..." (Tr. p. 3492). The Company has also expressed its willingness to adjust contract demands with its industrial customers (Tr. p. 3495).

82. In addition to the above revisions, the MPC also proposed a tax adjustment that allows the Company to " . . . increase the bill for electric service supplied under this rate scheduled (sic) by an amount equal to the proportionate parts of any taxes, other than those in effect on September 30, 1983" (Id., p. 8 of 10). LaCapra stated that this tax clause should appear on all the tariffs (Tr. p. 4349).

83. The MCC proposed three separate rate elements for the industrial class for each of the two cost allocation alternatives. These three rate elements include seasonally differentiated energy and demand charges, and customer charges (see Exh. No. 63, p. 93). In addition to the above non - TOD rate, the MCC also developed an alternative TOD

rate schedule.

84. The HRC, while opposing the MPC's proposed declining block energy rate structure, also proposed certain features for this class' rate design. As with the General Electric class, Power proposed seasonally differentiated demand charges at somewhat less than TDAC levels. Combined with this demand charge should be a flat energy rate to collect the remaining revenue responsibility (Exh. No. 39, p. 156).

85. Instead of a monthly fixed charge, Power proposes an "annual" minimum bill be used to assure that these customers' payments cover the fixed costs associated with the MPC standing ready to serve their large loads. The annual minimum payment would apparently collect both demand and energy costs.

86. Schoenbeck generally disagrees with the MPC's proposed Electric Contract rate design. Schoenbeck's principle concern, however, appears to be with the MPC's proposed minimum bill for this class. First, Schoenbeck finds the MPC's proposed minimum bill improper because it is based on the incremental cost of capacity. Second, Schoenbeck notes that the proposed minimum bill should be reduced by the potential gains (revenue) from off system sales. Schoenbeck then recommends a minimum bill charge no higher than $6. 52/kw, based on the Company's normalized cost-of-service study (see Exh. No. 56, pp. 22-25).

87. Schoenbeck also indicated that the MPC failed to account for $1.78 million in revenues that result from the Company's excess demand charge (Id. p. 25, and Schoenbeck's Data Response No. 3A to the Commission staff) .

88. Lively, for CICO, listed certain problems with the MPC's proposed rate design, and noted certain principles to follow when designing rates.

First, Lively noted that the principles "...that govern industrial rate design are no different from those that govern the design of rates for all classes" ; (Exh. No . 70, p . 31). Lively further noted that " . . . rate design should attempt to account for differences in load patterns within a class" (Id.).

89. Lively particularly disagrees with the MPC's proposed excess demand charge:

> Q. HOW DOES MR. LACAPRA PROPOSE TO CHARGE INDUSTRIAL CONTRACT CUSTOMERS FOR METERED DEMANDS THAT ARE IN EXCESS OF CONTRACT DEMAND?
>
> A. Mr. LaCapra has inserted a clause in the tariff for the Industrial Contract class that states:
>
> > If served, all kilowatts in excess of Contract Demand as specified in the Contract, will be billed at five (5) times the Demand Charge tail block of this schedule.
>
> This provision severely penalizes customers who use electricity in excess of the contractual commitment between the customer and Montana Power. ... In short, there is no rational reason for imposing a penalty charge for excess consumption. Thus, I believe that load increases over the contract demand should not incur a penalty in being charged five times the normal tail block rate. The tail block rate is sufficient. This excess revenue can be considered to be a hidden rate increase for Montana Power (Id., pp. 34, 35).

90. Lively went on to propose an interruptible rate with a demand charge based on avoided costs as an appropriate substitute for the MPC's penalty charge for loads in excess of contract demand:

> Q. WHAT IS THE APPROPRIATE WAY TO TREAT CUSTOMER LOADS IN EXCESS OF THE CONTRACT DEMAND?

A. I believe that Montana Power has no obligation to serve loads in excess of contract demand.

Such contracts give the utility the right to reduce the industrial's load during critical load periods such as when the utility must buy expensive power from others or is about to begin rotating blackouts. Interruptible contracts are common in the electric utility industry, though Montana Power does not have any with its customers. Certainly the "If served" clause could be a provision of such an interruptible contract.

Q. HOW WOULD YOU MODIFY THE PENALTY CLAUSE INTO AN INTERRUPTIBLE CLAUSE?

A. First, the demand charge should be reduced. One approach would be to use avoided costs. (Emphasis added). However, I would accept as a first approximation a reduction of the excess demand charge to the tariff level. Frequently, interruptible rates carry demand charges even lower than this. This is particularly true in cases where the development of load is to be encouraged (Id., pp. 35, 36).

91. As with previously discussed rate schedules, the Commission finds merit in moderating any rate design changes to the electric contract rates and rate design. First, a service charge of $50.00 per month shall be tariffed. This rate while not compensatory (the marginal cost is $1190. 00/customer/year) is a movement towards a compensatory rate. The demand rates should feature a 60 percent winter/summer differential in lieu of the existing 50 percent differential. As with the General Electric class, 10 percent of the resulting demand revenues are shifted to the energy function. Energy rates should continue to reflect a 20 percent seasonal differential. Table 4 below summarizes the approximate rates and calculations.

Table 4 Electric Contract Rate Design/1

Service Charge	$50.00/month

Demand/2	
Winter	$ 3.49/kw
Summer	2.18/kw
Energy/3	
Winter	2.2194¢/kwh
Summer	1.842¢/kwh

92. The Commission finds no merit in the Company's proposed excess demand charge, minimum monthly bill and tax adjustment rate provisions.

93. First, there is no economic rationale to the "five (5) times the demand charge" provisions for demand in excess of contract demand. If any rate were appropriate, it would be the rate for emergency purchases of nonfirm demand from the regional market.

94. Regarding the Company's proposed minimum monthly bill provision, the Commission finds that the existing contract provisions, as currently tariffed, are adequate. From Rule S14680 (p. 3 of 50) it is clear that the intent of the MPC's minimum bill provision is to insure a continuing recovery of the marginal costs of any additional production resources.

95. The Commission finds that a properly computed minimum bill would have to reflect the fungibility of the investment in question. That is, if a customer's load reduced substantially from maximum contract demand, the Company could over time use the freed-up generation resources to accommo date load growth or make off-system sales. Transmission and distribution investments will have different fungibility characteristics than generation plant. A properly designed minimum bill then would be much more complex than the simple concept suggested by the MPC. Until such issues are resolved, the Commission finds the existing rate provision adequate.

96. Regarding the Company's tax adjustment clause the Commission finds that rate adjustments should not be automatically passed through to customers as incurred. The proper forum for considering such expenses is a contested rate case, where claimed increases can be examined by the Commission and interested parties.

97. In the next electric rate case that deals with class cost of service and rate design the Company must address the issue of a reactive power charge for electric contract customers. The marginal cost of reactive power demand and the appropriate measure of billing determinant units must be addressed.

Lighting Classes.

98. There are currently three lighting schedules, Post-Top, Yard and Protective and Streetlighting. The streetlight schedule has one rate, $10.80/kw/month. The other lighting schedules have rates broken down by lighting technology e.g., mercury vapor, incandescent.

99. In the present docket the MPC submitted lighting rates considerably more complex and detailed than current tariffs. The streetlight rates are broken down initially into company-owned and customer-owned lights. A further level of refinement takes into account lamp wattage, lighting technology, type of pole and type of service (e. g., energy only) provided. The yard and protective lighting schedule was refined to include pole type.

100. In addition to the above schedules, the Company also proposed two new schedules including metered and flat-

demand outdoor lighting schedules. These two new schedules, as opposed to the above, contain three distinct rate elements including demand, energy and customer charges.

101. The basis of the proposed rates was LaCapra's marginal cost for energy and demand combined with marginal customer costs based on the National Economic Research Associates (NERA) cost approach.

102. In order to establish rates for all but the two new lighting schedules the Commission finds that marginal costs for energy and demand from the Power cost of service study should be used; the Company should combine these costs with marginal customer costs from the NERA study approach.

103. These combined costs, for each rate element and at full marginal cost, should in turn be scaled back on an equiproportional basis to yield revenues as determined from the marginal cost of service study. As opposed to a strict Ramsey pricing approach, the scaling back of all unit costs will ensure that the rates on the Company-owned and customer-owned streetlight schedules will not be the same.

104. At this time, the Commission finds no need to implement the Company's proposed ramping proposal, seasonally differentiated rates or on-off controls. While the streetlight class as a whole will experience a 28 percent increase in revenue requirements the Commission notes that the class revenue requirement out of Docket No. 80.4.2 (Order No. 4714d, Finding of Fact No. 34) was frozen. The Commission finds no reason to continue to moderate this class' revenue requirement.

105. The Commission has not closed the door for all

times on the matter of seasonal rates and on-off controls. Rather the Commission finds merit in moderating the degree of complexity resulting from rate design charges in this docket.

106. The Commission is concerned with the Company's proposed two new lighting schedules. On one hand the Company has filed rates that generate the Company's desired revenue requirement (indicating test year billing determinants are known with certainty). On the other hand the Company has indicated the " . . . requisite detail to identify number of units is not currently available" (see cover letter to the Company's August 20, 1984 marginal cost of service workpapers). The Commission can only wonder where the proposed Metered and Flat-demand outdoor lighting customers are currently billed, and how the proposed revenue requirement was arrived at without accurate billing determinants.

107. If at a later date billing determinants can be quantified, the Commission shall reconsider these rate schedules.

108. Promotional Rates. In his direct testimony, Wilson stated that due to the fact the MPC will have more than enough generation capability, with the Colstrip 3 and 4 additions, that " . . . the Company's ratepayers and the state's economy could be better off if new loads were attracted at promotional rates to make some use of the excess capacity" (Exh. No. 63, p. 94, 95).Wilson provided several comments regarding any temporary promotional rate proposal including anti-competitive concerns and the risk of temporary loads becoming permanent.

109. In hearing, Wilson elaborated on his position on

promotional rates indicating which costs, at a minimum, should be recovered and the likely customers such a rate could be directed at:

Q. Are you recommending that this Commission study the idea of promotional rates ?

A. I'm recommending that if a promotional rate proposal is made to the Commission, that that (sic) promotional rate proposal should be evaluated on its merits, and I'm warning that I would not recommend a generally applicable promotional rate. I would attempt to structure promotional rates very carefully so that they achieve intended results and minimize adverse consequences.

Q. Do you think the Commission ought to order the design of a promotional rate as a result of this case?

A. No, I'm not seeing evidence presented in this case that would warrant ordering a promotional rate, but I think it's an issue on which -- I think that it's an issue on which both the Company and the Commission should remain alert. If there is an opportunity to promote the use of otherwise unused resources at a level, at a revenue level that will make a contribution over and above the costs that are incurred, I think that it should be entertained seriously within the context of the other considerations that I discussed in that regard.

Q. If anybody were to come forward with a promotional rate, in the abstract, would that promotional rate look at all like the rates or the rate design that you are proposing in this case; that is to say, with some heavy emphasis on the energy component of the rate?

A. It very well could. I don't think that I agree with you that there's extraordinarily heavy emphasis on the energy component. There is an emphasis that the energy component or the rate not be below the system lambda. I would think that one of the considerations might be time of use on a promotional rate to the extent that if off-peak consumption were what was contemplated, that something that was related to the marginal running costs during off-peak periods plus a contribution

> would be a reasonable standard. I think that promotional rates of the types that have been introduced in some other jurisdictions, like Bonneville's aluminum start-up rate and soon, have made sense within the context of the jurisdictions where they've been implemented. (Tr. pp. 4528, 4529).

110. Power expressed his concern on the promotional effect of time-of day rates (Exh. No. 40, pp. 10-11). Power likened certain of Wilson's residential TOD proposals to pricing strategies of large industrial customers noting that such a strategy is promotional, dangerous, and costly.

111. Power further cautioned that promotional rates do not make sense even in the face of a surplus. This is because electric energy consumption decisions are typically long-run decisions (Id., p. 12).

112. The Commission finds merit in Power's expressed concerns. That is, energy consumption decisions do have long-run implications. In turn, long-run investment decisions should not be based on short-run discounted electric rates.

113. Interruptible Rates. When a utility's resources are insufficient to meet loads, a utility has a number of options available depending on the extent to which advance notice exists of the power shortage. The longer the notice, the better able a utility is to plan resources to meet the expected load with normal resource acquisition.

114. For circumstances when loads exceed resources on a very short notice such as the "megafreeze" of 1983, the utility can rely on emergency purchases from inter-company pool arrangements. Alternatively, the utility may coordinate with certain customers to reduce or eliminate their load - interrupt -- for the duration of the power shortage.

115. There are clearly two distinct issues involved with an interruptible resource acquisition. The first is general and deals with the economic merit of such a resource acquisition: Is it the least cost resource to meet an unexpected power shortage? The second deals with the cost -- ultimately the interruptible rate -- of such a resource and, in fact, should be known before such a resource is pursued and acquired.

116. In the current docket Stauffer Chemical's John Lekashman expressed his Company's interest in an interruptible rate:

> Q. ARE THERE POTENTIAL OPTIONS?
>
> A. Stauffer has a major investment in Montana and is committed to do all that it possibly can to maintain the economic viability of the Silver Bow Plant. The switch from BPA to Montana Power Company was one example of this commitment. If the rate increase for Stauffer based on the cost to serve is determined to be far in excess of the earlier forecasts of 35%, Stauffer must explore alternatives to reduce power rates in order to assure the plant's continued operation. One such alternative is an appropriate interruptible rate which would provide a significant rate reduction in exchange for Stauffer's accepting lower quality power rather than firm power. At the time the plant was switched for BPA to Montana Power, we requested interruptible service rather than firm service. Montana Power did not have such a rate but held out the prospect of offering it to us in the future. A phosphorus plant offers unique operating characteristics which permit instantaneous interruption of large high load factor customer which makes an interruptible rate a real benefit to a utility. Our Silver Bow Plant is the only electric furnace plant in the nation which operates on firm power with a better quality of power than required. With the proper rate incentives, Stauffer is desirous of such a reduced quality of power as a means of maintaining the Silver Bow plant's economic viability. (Exh. No. 48, p. 8).

117. In hearing Lekashman made clear his Company's interest in negotiating an interruptible contract with the MPC and

also noted that Stauffer has not designed such a rate:

Q. Mr. Lekashman, on page 3 of your direct testimony, you stated that if MPC could provide an appropriate interruptible rate schedule that would offer Stauffer a significant rate reduction in exchange for Stauffer's accepting a lower quantity (sic) of power than firm power, that Mr. Stauffer would be interested in such a rate.
What does Stauffer see to be an appropriate interruptible rate structure for Stauffer in that case?

A. It's very difficult for me to talk about the specifics of an interruptible here in Montana. The circumstances are different. In Florida, I understand the circumstance. I could describe it. You could draw a parallel if that is a worthwhile piece of information for you. In Florida, the requirement of a spinning reserve is necessary. And the utility has to pay for the fuel, keep the facilities going, and the nature of the load such as we have in Tarpon Springs, they can shut the plant down in relatively in an instant all except a small amount of firm power to keep it going. So, by selling that power to us, they get the revenue for burning that fuel and maintenance and some of the demand that is associated with that facility. So, that is a significant benefit to the utility in Florida.
I think there are differences up here in Montana, but I'm not expert enough to be able to amplify on them.

Q. Well, could you explain why in this docket Stauffer has not proposed an interruptible rate schedule to be considered in this docket?

A. When you mean "proposed," we have proposed an interruptible rate to the utility. Excuse me, we've proposed discussing and negotiating one.

Q. What I'm asking is whether you actually have one available that you have come up with for Montana that is actually being discussed with MPC.

A. The technical terms of how to do that are quite difficult, and we have had one or two conversations with the utility on the subject. Further progress on it has in with regard to this proceeding.

SO, I think the answer to your question is, we have not a specific proposal as of yet.

Q. Now, you stated on page 8 of your direct testimony that you had requested, or Stauffer had requested, interruptible service from Montana Power rather than firm power at the time that Stauffer was switching from BPA to MPC. You also state that Montana Power held out the prospect of offering Stauffer an interruptible rate in the "future", and by the "future", I would like to know how far ahead in terms of years you were discussing at that point.

A. I don't know the exact period of time. I was not at those discussions. It was really as soon as it was practicable and sensible to do so (Tr. pp. 3766-3768).

118. Lively stated that while there are a myriad of interruptible rate design possibilities. One possibility would feature an incentive that is in effect only when a customer is interrupted (Tr. pp. 5057, 5058).

119. The HRC conditionally approves of an interruptible rate:

First existing customers who are, in theory, paying fully compensatory, cost-based rates would not now be allowed to switch to such rates. Second, such loads have to be truly interruptible (Emphasis added) (Exh. No. 40, p. 21).

120. Power further elaborated:

Given that MPC is in a state of surplus, it could assure perfectly reliable service to nominally interruptible customers for some time to come. But if the interruptible rate covers only part of the fixed costs of service, a current firm customer could shift to interruptible status, get the same quality of service, but pay lower rates. Other firm customers, of course, would have to pick up the burden of the fixed costs being shed by the industrial customer. This would simply be disguised subsidization. If, in the future, as MPC actually begins to plan construction of a new facility or enter into a long-term contract to purchase power, an industrial customer is willing to surrender its right to firm service for non-firm service which it knows will include regular interruption, an interruptible rate should be negotiated and the planned expansion delayed as that firm load is dropped from the load the utility plans to meet.

But the load must be completely and freely interruptible by the utility. The load must be ignored in energy planning and any Commission calculation of excess capacity (Id., p. 21).

121. Once more, the Commission finds little reason to attempt to quantify and tariff an interruptible rate for Stauffer or any other customer. The issues raised here must first be addressed by an intervenor or MPC. When the issues have been addressed the Commission will take appropriate action.

Revenue Requirement

122. Order No. 5051c set forth a final increase in annual revenues of $4,106,915. Due to the Commission's adjustment to the Anaconda Company's deficiency payments combined with the final rates in this docket a slight increase in annual revenues would accrue to the MPC. However, given the apparent complexity of the calculation the apparent costs of the adjustment may outweigh the benefits. Consequently, the adjustment is not necessary.

CONCLUSIONS OF LAW

1. All Findings of Fact are hereby incorporated as Conclusions of Law.

2 The Applicant, Montana Power Company, furnishes electric service to consumers in Montana, and is a "public utility" under the regulatory jurisdiction of the Montana Public Service Commission. §69-3-101, MCA.

3. The Montana Public Service Commission properly exercises jurisdiction over Montana Power Company's rate and operations. §69-3-102, MCA, and Title 69, Chapter 3, Part 3, MCA.

4. The Montana Public Service Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this docket. §69-3-303, MCA, §69-3-104, MCA, and Title 2, Chapter 4, MCA.

5. The cost of service approved herein is just, reasonable, and not unjustly discriminatory. §69-3-330, MCA and §69-3-201, MCA.

ORDER

THE MONTANA PUBLIC SERVICE COMMISSION HEREBY ORDERS:

1. The Montana Power Company shall design rates to generate authorized revenues which are consistent with the Findings of Fact entered by the Commission in this Order. These rates will be effective for service rendered on and after September 20, 1984.

2. The Montana Power Company shall submit working papers revealing, in detail, the unit rates and class revenue responsibilities. The working papers are to be filed by September 30, 1984. The working papers should be provided to

those intervenors who request them.

3. The Montana Power Company shall file rate schedules which reflect an electric utility revenue requirement of $176,649,300.

4. All other motions or objections made in the course of these proceedings which are consistent with the findings, conclusions, and decision made herein are granted; those inconsistent are denied.

DONE AND DATED this 18th day of September, 1984 by a vote of 5-0.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION.

THOMAS J. SCHNEIDER, Chairman

JOHN B. DRISCOLL, Commissioner

HOWARD L. ELLIS, Commissioner

CLYDE JARVIS, Commissioner

DANNY OBERG, Commissioner

ATTEST:

Madeline L. Cottrill
Secretary

(SEAL)